Topic	No	Language	Comments
Definitions	XXX	Area of review - The area surrounding an injection well or injection project to a radius calculated according to the criteria set forth in section XXX, or a fixed radius of a minimum of one quarter mile for disposal or enhanced recovery operations, or __________ for cyclic steam injection operations. In the case of directional or horizontal well bores, the area of review will extend the calculated radius or fixed radius along the inclined or horizontal portion of the wellbore within the proposed injection zone.	Add section for definitions
		Base-of-Freshwater (BFW) - The base of the interface between different water quality at a threshold of 3,000 mg/l Total Dissolved Solids (TDS).	
		Class II Injection Well - Class II injection wells are defined by the United States Environmental Protection Agency (US EPA) in 40 Code of Federal Regulations (CFR) 146.5 and inject the following fluids: A. Fluids that are brought to the surface in connection with conventional oil or natural gas production. The fluids may be commingled with waste-water from gas plants, which are an integral part of production operations (unless the waste water is classified as a hazardous waste at the time of injection). B. Fluids used for enhanced oil recovery (EOR), including natural gas for pressure maintenance; and C. Hydrocarbons for storage purposes that are liquid at standard temperature and pressure.	
		Approved Class II Fluids - Aside from produced brines, the State Oil and Gas Supervisor has determined that a Class II water disposal injection well may accept the following nonhazardous fluids types that originate from oilfield activities 1. Diatomaceous earth filter backwash; 2. Thermally enhanced oil recovery (TEOR) cogeneration plant fluid; 3. Water-softener regeneration brine; 4. Air scrubber waste; 5. Drilling mud filtrate; 6. Tank bottoms; 7. Slurrified crude-oil saturated soils; 8. Slurrified drill cuttings.	
		The State Oil and Gas Supervisor may approve additional Class II fluids that meet the criteria of Class II injection under 40 CFR 146.5 above	

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		Commercial disposal well - A well which is specifically engaged in the business of underground injection of fluids brought to the surface in connection with the production of oil and/or gas and generated by third party producers for a fee or compensation.	
		Confining zone – The geological formation or formations, or portion of a formation that is capable of limiting fluid movement out of the injection zone.	
		Cyclic steam injection well – A well in which steam is periodically and cyclically injected into a formation, then subjected to a thermal soak period, after which the well is put back on production to produce the thinned crude oil.	
		Cyclic Steaming (also referred to as steam cycling, steam soak, steam stimulation, intermittent steam injection, or huff 'n puff) - Steam is injected into an oil well for a few days or weeks ("huff" phase). The well is then closed in for a period of time, depending on the optimum soaking period of the reservoir, and then reopened as a producer ("puff" phase).	
		Damage - Any resulting action or situation that could cause harm to life, health, property, or natural resources. This includes, but is not limited to migration of any injection fluid outside of a permitted zone; casing deformation as a result of subsidence or uplift; any unauthorized discharge to land; or any subsidence or uplift that impacts adjacent activity.	Needs improvement?
		Disposal well – A well which injects fluids for purposes other than enhanced recovery those fluids brought to the surface in connection with the production of oil and/or gas.	
		Enhanced recovery injection well - A well in which gas, water, or other fluids are injected into an oil or gas reservoir to increase pressure or retard pressure decline in the reservoir, displace hydrocarbons in the reservoir, or alter the physical properties of hydrocarbons in the reservoir for the purpose of increasing the recovery of oil or other hydrocarbons and shall include secondary or additional operations. This is to include all thermal processes.	
		Gas Injection well-	Definition needed
		Injection zone – The geological formation, group of formations, or portion of a formation that receives the injection of fluids through a well.	
		Pressure Maintenance Injection – injection where fluids are injected into the producing horizon in an effort to build up and/or maintain the reservoir pressure in an area which has not reached the advanced or "stripper" state of depletion	Improve definition – what is “stripper”…
		Steamflooding (also referred to as continuous steam injection or steam drive) - Steam is injected continuously through one well, or group of wells, while oil is produced through a different well, or group of wells.	

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		Underground Injection and Disposal - The injection of gas, liquefied petroleum gas, air, water, or any other medium into any reservoir for the purpose of maintaining reservoir pressure, or for the purpose of secondary, or other enhanced recovery, or for storage, or the injection of water into any formation for the purpose of water disposal.	definition to clearly differentiate injection of fluid for purposes of stimulation
		Underground Source of Drinking Water (USDW) - The following EPA definition of a USDW means an aquifer or its portion that is not exempted and: A. Supplies any public water system, or B. Contains a sufficient quantity of ground water for human consumption, and 1. Currently supplies drinking water for human consumption, or 2. Contains fewer than 10,000 mg/l total dissolved solids.	USDW definition should be consistent with Protected Waters definition in SB 4 regulations. It seems that Protected Waters as defined is more restrictive than USDW? Public water system - can be further defined based on federal definition or EPA study dated January 4, 1993 suggesting an aquifer should be able to yield at least 1 gallon of water per minute to be afforded USDW protection.
		Waterflooding – The process in which water is injected into a producing horizon in sufficient quantities and under sufficient pressure to stimulate the production of oil from other wells in the area. This injection process shall be limited to those areas in which the wells have reached an advanced state of depletion and are regarded as what is commonly referred to as "stripper" wells.	
		Zone of endangering influence - zone of endangering influence for a single injection well is the radius encompassing the lateral distance in which existing or induced pressures in the injection zone may cause the migration of injection and/or formation fluid into a USDW or hydrocarbon zone or to the surface. For an injection project, it includes the project area plus a circumscribing area the width of which is the lateral distance from the perimeter of the project area, in which the pressures in the injection zone may cause the migration of injection and/or formation fluid into a USDW or hydrocarbon zone or to the surface.	
Project Data Requirements	1724.7	The data required to be filed with the district deputy include the following, where applicable:	
		(a) An engineering study, including but not limited to:	
		(1) Statement of primary purpose of the project.	

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		(2) Reservoir characteristics of each injection zone, such as porosity, permeability, average thickness, areal extent, fracture gradient, original and present temperature and pressure, and original and residual oil, gas, and water saturations.	
		(3) Reservoir fluid data for each injection zone, such as oil gravity and viscosity, water quality, and specific gravity of gas.	
		(4) Casing diagrams, including cement plugs, and actual or calculated cement fill behind casing, of all idle, plugged and abandoned, or deeper-zone producing wells within the area affected by the project, and evidence that plugged and abandoned wells in the area will not have an adverse effect on the project or cause damage to life, health, property, or natural resources.	
		(5) The planned well-drilling and plugging and abandonment program to complete the project, including a flood-pattern map showing all injection, production, and plugged and abandoned wells, and unit boundaries.	
		(b) A geologic study, including but not limited to: DRAFT - CONFIDENTIAL	
		(1) Structural contour map drawn on a geologic marker at or near the top of each injection zone in the project area.	
		(2) Isopachous map of each injection zone or subzone in the project area.	
		(3) At least one geologic cross section through at least one injection well in the project area.	
		(4) Representative electric log to a depth below the deepest producing zone (if not already shown on the cross section), identifying all geologic units, formations, freshwater aquifers, and oil or gas zones.	
		(c) An injection plan, including but not limited to:	
		(1) A map showing injection facilities.	
		(2) Maximum anticipated surface injection pressure (pump pressure) and daily rate of injection, by well.	
		(3) Monitoring system or method to be utilized to ensure that no damage is occurring and that the injection fluid is confined to the intended zone or zones of injection.	
		(4) Method of injection.	

		(5) List of proposed cathodic protection measures for plant, lines, and wells, if such measures are warranted.	
		(6) Treatment of water to be injected.	
		(7) Source and analysis of the injection liquid.	
		(8) Location and depth of each water-source well that will be used in conjunction with the project.	
		(d) Copies of letters of notification sent to offset operators.	
		(e) Other data as required for large, unusual, or hazardous projects, for unusual or complex structures, or for critical wells. Examples of such data are: isogor maps, water-oil ratio maps, isobar maps, equipment diagrams, and safety programs.	
		(f) All maps, diagrams and exhibits required in Section 1724.7(a) through (e) shall be clearly labeled as to scale and purpose and shall clearly identify wells, boundaries, zones, contacts, and other relevant data.	
	1724.8	Data Required for Cyclic Steam Injection Project Approval. ~~The data required by the Division prior to approval of a cyclic steam (steam soak) project include, but are not limited to, the following:~~ ~~(a) A letter from the operator notifying the Division of the intention to conduct cyclic steam injection operations on a specific lease, in a specific reservoir, or in a particular well.~~	
		~~(b) If cyclic steam injection is to be in wells adjacent to a lease boundary, a copy of a letter notifying each offset operator of the proposed project.~~ The data required by the Division prior to approval of a cyclic steam (steam soak) project shall be the same as for other enhanced oil recovery injection projects as outlined in Section 1724.7, where applicable.	Minimum data requirements should be the same as for other injection EOR projects.
	1724.9	Gas Storage Projects The data required by the Division prior to approval of a gas storage project include all applicable items listed in Section 1724.7(a) through (e), and the following, where applicable: (a) Characteristics of the cap rock, such as areal extent, average thickness, and threshold pressure. (b) Oil and gas reserves of storage zones prior to start of injection, including calculations. (c) List of proposed surface and subsurface safety devices, tests, and precautions to be taken to ensure safety of the project. (d) Proposed waste water disposal method.	
Injection Project	XXX	Approval must be obtained from this Division before any subsurface injection or disposal project can	

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Approval		begin. This includes all EPA Class II wells and air- and gas-injection wells. The operator requesting approval for such a project must provide the appropriate Division district deputy with any data that, in the judgment of the Supervisor, are pertinent and necessary for the proper evaluation of the proposed project.	
Approval of New Projects	XXX		Preamble
		1. Injection fluid shall be confined to the permitted zone of injection. This is required whether or not a USDW is present. Confinement means: a) All wells completed prior to January 1, 1978, within the “area affected by the (injection) project” (Area of Review), must have a minimum of 100 feet of cement in the annular space behind casing above the oil and gas zones and anomalous pressure intervals. All well after January 1, 1978, shall have 500 of cement in the annular space behind casing unless known geologic conditions supported adoption of a variance that has been document by the Division at the time the cement job. For water disposal wells with proposed injecting into non-hydrocarbon zone, there must be 100 feet of cement across and above the top of the intended injection zone. A cement bond log (CBL) or temperature survey (other methods may be used if approved by the State Oil and Gas Supervisor) shall be used to evaluate and confirm top of cement in the annular space behind casing. If a CBL or temperature log is not available, the theoretical top of cement shall be calculated. When calculating theoretical cement top, there must be enough cement to fill the annular space to at least 150 feet above the oil and gas zones or anomalous pressure interval.	This 150’ allows for a margin of safety when calculating theoretical top of cement. (The margin of safety allows for variations in hole size, cementing procedures, pre-flush conditions and displacement of fluids, and provides a conservative estimate of the top of cement.)
		b) All plugged and abandoned wells within the area affected by the project (AOR) must have cement across all perforations and shall extend at least 100 feet above the top of a landed liner, the uppermost perforations, the casing cementing point, the water shutoff holes, or the oil and gas zone, whichever is higher. In those rare cases where cement does not cover all perforations, for reasons such as the presence of junk in the hole, damaged casing, or that the well was drilled before clear standards were expressed in regulation, there must be, at a minimum, zonal isolation.	Better to cite date when well was drilled as cut-off date?
		c) Injection fluid shall not migrate to a different zone through another well, geologic structure, faults, fractures, or fissures, or holes in casing. This includes prevention of injection fluid break through to the surface where the injection zone is exposed at the surface.	
		d) Injection pressure shall be maintained below fracture pressure, as determined by approved step-rate tests. The Maximum Allowable Surface Pressure (MASP) shall be determined by taking 95% of the fracture pressure, as determined by a step-rate test. Friction loss shall not be used in determining the MASP, but rather will provide for an additional safety margin of error.	Allow for highly deviated or horizontal wells…
		e) All injection wells drilled after January 1, 1977 must have, in addition to cement above the oil and	

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		gas zones, cement placed across the base of freshwater interface (BFW) with at least 100 feet above the BFW interface.	
		2. Area affected by the project" (Division's AOR) will be determined using 1, 2 and 3 below: (1) One of the following methods: a. Fixed radius (minimum ¼ mile) or b. Calculated area, whichever is greater <u>and</u> (2) Must include the distance in which the pressures in the injection zone may cause the migration of the injection and/or formation fluid outside of the existing injection zone, <u>and</u>, DRAFT - CONFIDENTIAL (3) The calculated injection time equal to the expected life of the injection project.	
		3. Step-rate test(s) must be run to determine the fracture pressure of the injection zone(s) Step-rate tests should be conducted with a downhole pressure gauge set near the injection zone. If this requirement cannot be met, a surface pressure vs. pumping time gauge with digital real-time readout should be available for the duration of the test to meet test criteria of pressure stability for every pump rate.	
		4. Mechanical Integrity Tests (MIT) shall be performed on all injection. Prior to injection, each well must pass a pressure test of the casing or casing-tubing annulus to determine the absence of leaks. Within 3 months after injection has commenced a second MIT must be performed using a radioactive (RA) survey tool, and a static. The District Deputy may modify the schedule if supported by evidence, and as long as it does not exceed five years between MITs. For shallow thermal diatomite wells, regular temperature surveys may be requested for the migration part of the MIT.	
		5. If there is insufficient data to determine if the injection fluid is confined to the intended zone, an approved monitoring program may be requested and used to confirm injection	

		fluid confinement. 6. All existing injection projects will have an annual project review. The purpose of the annual injection project review is to determine if the injection project still meets the permit conditions and is meeting its purpose; ensure that all required testing has been performed; determine if there have been any changes to the project, including if any wells have been drilled, reworked, or plugged and abandoned within the AOR and if the work was completed appropriately, to confirm that the injection fluid is confined to the permitted zone of injection; and to confirm that no damage is occurring as a result of the injection project.	
		7. All required Mechanical Integrity Testing (MIT) must be performed in two parts. The first part is the pressure test of the casing. The second part of the MIT must be performed within 3 months after injection begins. After that, testing must occur at the following frequencies: a) Water disposal wells: at least once per year b) Waterflood wells: at least once every two years c) Steamflood wells: at least once every five years d) Cyclic steam wells: at least once per year The district deputy may grant a variance to this schedule for individual wells, but only for good cause if supported by documented evidence. Cyclic steam wells may avoid this testing schedule if the operator has a SCADA system to provide real time monitoring to detect casing failures that has been approved by the Supervisor	
		8. All Standard Annular Pressure Tests (SAPT) must be performed at least once every five years. For those situations where there is only a single string of casing across a USDW (10,000 mg/l TDS), the SAPT must be tested at the approved MASP for the well. The Supervisor may consider a monitoring option for wells that have concerns on casing pressure tests to very high pressures exceeding 3,000 psi.	
AE		9. If the proposed aquifer contains fewer than 10,000 mg/l TDS and is an aquifer that has not been exempted by the US EPA, then an aquifer exemption is required prior to injection. The recommendation for exemption must be initiated by the project applicant and all supporting documentation must be submitted to the Division for evaluation. If the Division determines that an	

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		aquifer exemption is appropriate, the Division will add any additional information as necessary and submit the request to the Regional Water Quality Control Board to receive a concurrence. The Division will not forward the request to the US EPA until all of the RWQCB concerns have been addressed. The EPA must approve the exemption before the Division can approve the project. 1. For an aquifer or a portion thereof, with fewer than 10,000 mg/l TDS, there must be a determination by the applicant that: a. The aquifer is not a current source of drinking water; and b. The aquifer cannot now, and will not in the future, serve as a source of drinking water because the aquifer is mineral, hydrocarbon, or geothermal energy producing, or that the applicant can demonstrate that the aquifer contains minerals or hydrocarbons that, considering their quantity and location, are expected to be commercially producible. 2. For an aquifer with a TDS level between 3,000 and 10,000 mg/l TDS that is not reasonably expected to supply a public water system, the applicant must submit: a. A declaration that the aquifer is not a current source of drinking water and that the aquifer will not reasonably be expected to supply a public water system. This declaration should be made by the local Regional Water Quality Control Board. b. Data on the depth and lateral extent of the aquifer and the location and depth of any drinking-water wells in the area. (The injection wells should be at least double the depth of the deepest well providing drinking water to qualify for an exemption). c. Information relative to the aquifer, such as: 1. The distance to existing towns. 2. The ownership and types of land-use in the area. 3. The availability of alternate water sources to the area (surface and groundwater). 4. Any unusual geology. d. The type of constituents and TDS in the formation fluid (preferably a water analysis). e. The yield of water. 3. For an aquifer with fewer than 3,000 mg/l TDS that is situated at a depth or location that makes recovery of water for drinking purposes economically or technologically impractical, the applicant must submit: a. A declaration that the aquifer is not a current source of drinking water. b. The type of constituents and TDS in the formation fluid (preferably a water analysis). c. The yield of water. d. The depth and lateral extent of the aquifer, and the location and depth of any wells providing drinking water in the area. (The aquifer should be three times deeper than the deepest well providing drinking water to qualify for an exemption). e. Information relative to the aquifer, such as:	

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		1. The distance to existing towns. 2. The ownership and types of land-use in the area. 3. The availability of alternative water sources (surface and groundwater). 4. Any unusual geology. f. An economic analysis. 4. The aquifer is so contaminated that it would be economically or technologically impractical to render that water fit for human consumption. The applicant must submit: a. A declaration that the aquifer is not a current source of drinking water. b. The start-up date and volumes of fluid previously injected. c. An analysis of the formation fluids (initial and current). d. Characteristics of the injected fluid. e. An assessment of the recoverability and treatment of the contaminated water. f. An economic analysis to indicate the cost of treating the water to raise it to drinking water standards (EPA has documents on this subject).	
Agency Notice		10. The Division shall provide the local Regional Water Quality Control Board with the application data for their review. The Division will allow 14 calendar days from the date of transmittal for the RWQCB to comment on the project. The Division will not issue an approval to inject until all of the Regional Water Quality Control Board's concerns have been addressed.	
Public Notice		11. A public notice must be published in a local newspaper of general circulation in the project area for three (3) days.	
		12. Public Hearing Procedures If a public hearing is necessary, a notice of public hearing shall be published in a local newspaper of general circulation in the project area for 3 consecutive days. If the local newspaper is published on a weekly basis, the notice needs to be published only once. The hearing date should be at least 30 calendar days following the publication of the notice.	
EPA Class I & V wells in oil/gas field		13. Industrial Waste Disposal Wells (US EPA Class I and certain Class V wells) A. Class I Wells: Even though the Division only has primacy for Class II wells, the Division will remain involved with Class I wells that are oil-industry related, located within an oilfield, or in an area where hydrocarbons may be encountered. All applicants for new Class I wells, including wells located within the administrative boundary of	

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		an oilfield, must file proposals with and obtain a permit from the US EPA. The Division will not issue a permit to inject for a Class I well within an oilfield, but the Division will review and make applicable comments and recommendations to the US EPA regarding the following: 1. An API number, if warranted. 2. Required blowout prevention equipment. 3. Measures for the protection of any petroleum resource. 4. Measures for the protection of useable water. 5. Casing and cementing programs. 6. Requirements for reporting injection volumes and pressures to the Division, if warranted. 7. Surveillance and monitoring requirements. If an existing oil and gas or Class II injection well is converted to a Class I injection well, the Division shall ensure that the US EPA, the operator, and local jurisdictions are notified that the well is no longer the responsibility of the Division once the conversion is approved by the US EPA. Even though the Division does not issue permits for Class I wells, inspecting well conditions and witnessing mechanical integrity tests for Class I wells within oilfields may be performed by the Division.	
		B. Class V Wells: For Class V wells located within an oilfield administrative boundary, the Division will issue a well-construction permit that establishes well construction and monitoring requirements, including the following: 1. An API number.* 2. Required blowout prevention equipment. 3. Measures for the protection of any petroleum resource. 4. Measures for the protection of useable water. 5. Casing and cementing programs. 6. Requirements for reporting injection volumes and pressures to the Division. 7. Surveillance and monitoring requirements. 8. A statement that no perforating or injection can take place until the Regional Water Quality Control Board has issued waste-discharge requirements. Approval for injection of the fluid type must come from the RWQCB. An operator requesting a Class V injection permit located within an oilfield boundary will receive a dual permit: The Division issue a well construction and monitoring permit and the RWQCB will permit the injection fluid waste discharge requirements.	
	1724.10	Filing, Notification, Operating, and Testing Requirements for Underground Injection Projects.	

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		(a) The appropriate Division district deputy shall be notified of any anticipated changes in a project resulting in alteration of conditions originally approved, such as: increase in size, change of injection interval, or increase in injection pressure. Such changes shall not be carried out without Division approval.	
		(b) Notices of intention to drill, redrill, deepen, or rework, on current Division forms, shall be completed and submitted to the Division for approval whenever a new well is to be drilled for use as an injection well and whenever an existing well is converted to an injection well, even if no work is required on the well.	Should include resetting of packers
		(c) An injection report on a current Division form or in a computerized format acceptable to the Division shall be filed with the Division on or before the 30th day of each month, for the preceding month.	
		(d) A chemical analysis of the liquid being injected shall be made and filed with the Division whenever the source of injection liquid is changed, or as requested by the Supervisor.	
		(e) An accurate, operating pressure gauge or pressure recording device shall be available at all times, and all injection wells shall be equipped for installation and operation of such gauge or device. A gauge or device used for injection-pressure testing, which is permanently affixed to the well or any part of the injection system, shall be calibrated at least every six months. Portable gauges shall be calibrated at least every two months. Evidence of such calibration shall be available to the Division upon request.	Reword to include new technology
		(f) All injection piping, valves, and facilities shall meet or exceed design standards for the maximum anticipated injection pressure, and shall be maintained in a safe and leak-free condition.	Review for consistency with Facilities regulations
		(g) All injection wells, except steam, air, and pipeline-quality gas injection wells, shall be equipped with tubing and packer set immediately above the approved zone of injection within one year after the effective date of this act. New or recompleted injection wells shall be equipped with tubing and packer upon completion or recompletion. Exceptions may be made when there is: (1) No evidence of freshwater-bearing strata. (2) More than one string of casing cemented below the base of fresh water. (3) Other justification, as determined by the district deputy, based on documented evidence that freshwater and oil zones can be protected without the use of tubing and packer.	Needs clarification
		(h) Data shall be maintained to show performance of the project and to establish that no damage to life, health, property, or natural resources is occurring by reason of the project. Injection shall be stopped if there is evidence of such damage, or loss of hydrocarbons, or upon written notice from the Division. Project data shall be available for periodic inspection by Division personnel.	

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		(i) To determine the maximum allowable surface injection pressure, a step-rate test shall be conducted prior to sustained liquid injection. Test pressure shall be from hydrostatic to the pressure required to fracture the injection zone or the proposed injection pressure, whichever occurs fi rst. Maximum allowable surface injection pressure shall be less than the fracture pressure. The appropriate district office shall be notified prior to conducting the test so that it may be witnessed by a Division inspector. The district deputy may waive or modify the requirement for a step-rate test if he or she determines that surface injection pressure for a particular well will be maintained considerably below the estimated pressure required to fracture the zone of injection.	Should be consistent with previous wording in LOE
		(j) A mechanical integrity test (MIT) must be performed on all injection wells to ensure the injected fluid is confined to the approved zone or zones. An MIT shall consist of a two-part demonstration as provided in subsections (j)(1) and (2). (1) Prior to commencing injection operations, each injection well must pass a pressure test of the casing-tubing annulus to determine the absence of leaks. Thereafter, the annulus of each well must be tested at least once every five years; prior to recommencing injection operations following the repositioning or replacement of downhole equipment; or whenever requested by the appropriate Division district deputy. (2) When required by subsection (j) above, injection wells shall pass a second demonstration of mechanical integrity. The second test of a two-part MIT shall demonstrate that there is no fluid migration behind the casing, tubing, or packer. (3) The second part of the MIT must be performed within three (3) months after injection has commenced. Thereafter, water-disposal wells shall be tested at least once each year; waterflood wells shall be tested at least once every two years; and steamflood wells shall be tested at least once every five years. Such testing for mechanical integrity shall also be performed following any significant anomalous rate or pressure change, or whenever requested by the appropriate Division district deputy. The MIT schedule may be modified by the district deputy if supported by evidence documenting good cause. (4) The appropriate district office shall be notified before such tests/surveys are made, as a Division inspector may witness the operations. Copies of surveys and test results shall be submitted to the Division within 60 days.	
		(k) Additional requirements or modifications of the above requirements may be necessary to fit specific circumstances and types of projects. Examples of such additional requirements or modifications are: (1) Injectivity tests. (2) Graphs of time vs. oil, water, and gas production rates, maintained for each pool in the project and available for periodic inspection by Division personnel.	Update

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		(3) Graphs of time vs. tubing pressure, casing pressure, and injection rate maintained for each injection well and available for periodic inspection by Division personnel. (4) List of all observation wells used to monitor the project, indicating what parameter each well is monitoring (i.e., pressure, temperature, etc.), submitted to the Division annually. (5) List of all injection-withdrawal wells in a gas storage project, showing casing-integrity test methods and dates, the types of safety valves used, submitted to the Division annually. (6) Isobaric maps of the injection zone, submitted to the Division annually. (7) Notification of any change in waste disposal methods.	
		Standard Annular Pressure Testing (SAPT) A Standard Annular Pressure Test (SAPT) is required prior to injection, and at least once every five years thereafter for all injection wells. The following conditions must be met when conducting the SAPT: A. No perforations are open above the packer. 1. Hydraulic test – The well test shall be tested with a minimum of 200 psi or the Maximum Allow Surface Pressure (MASP), whichever is higher, for at least 15 minutes, with a maximum pressure loss of 10 percent. 2. Gas test - The well test shall be tested with a minimum of 200 psi or the Maximum Allow Surface Pressure (MASP), whichever is higher, for at least 15 minutes, with a maximum pressure loss of 10 percent.	To be incorporated to casing pressure test in 1724.10 Should be reworded to clarify.
		B. Perforations and/or holes above packer. 1. Fluid level (sonic) test. a. Must have cement behind casing (above perforations/holes). b. Perforations/holes must be below USDW'S. 2. Pull tubing and packer, run a bridge plug, and pressure test. Any other method requested by the operator must be approved by the Division prior to running the test.	
		Mechanical Integrity Testing MIT Failures Injection shall cease if the MIT survey should indicate a lack of integrity. For injection wells that fail an MIT, an evaluation mast be made to determine whether or not an endangerment of a USDW exists.	This section is to be organized to fit into the present language re MITs. This is an expansion and detailing of the MIT process. There are subcategories that has to be organized.

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If a USDW is present, The Division will contact the Regional Water Quality Control Board and provide the Board with details of any possible contamination.

MASP Exceeded

Delinquent Mechanical Integrity Test (MIT)

A. Survey is determined delinquent.
B. Operator is notified to run an MIT within 60 days.
C. If the operator does not run the MIT within 60 days as directed, the District Deputy may rescind the permit by issuing a letter rescinding the individual injection-well permit and ordering the operator to: (1) shut-in the well within 24 hours; (2) disconnect the injection line at the wellhead within 10 days; and (3) notify the appropriate district office when the injection line has been disconnected.

The District Deputy must rescind the permit if the MIT is not run within 90 days.

Internal Mechanical Integrity Failure

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A.Tubing Or Packer Failure

1. The District Deputy shall issue a written order to shut-in the well immediately, and to repair the well within 60 days. Failure to shut-in the well and repair the failure may result in either a civil penalty and/or order to plug and abandon the well. When appropriate, the operator must file a notice and receive a permit before work is commenced.

2.A MIT shall be required following repair if the well is returned to injection.

B.Casing Failure Located Below The Packer

1. If fluid is exiting a hole or cemented-off perforations (e.g., Water shut-ff (WSO)) located below the packer, but within the permitted zone, no action is necessary. However, a recalculation of the maximum allowable surface pressure may be necessary.

2. If fluid is exiting a hole or cemented-off perforations (e.g., WSO) located below the packer and is entering a zone that has received an aquifer exemption, but has not been permitted for injection by the Division:

a. The operator must either repair the mechanical problem or amend the project to include the

		nonpermitted zone into the injection project by submitting the required project data within 60 days. A revised project approval letter will be issued by the Division. No further injection is permitted until the project receives approval. b. If the operator fails to repair the well or amend the project within 60 days, the District Deputy may rescind the permit.. c. An MIT is required following repair if the well is returned to injection. If the operator fails to run the MIT, ______ d. The District Deputy must rescind the permit if the operator fails to repair the well or amend the project within 120 days. 3.If fluid is exiting a hole or cemented-off perforations (e.g. WSO) located below the packer and is entering a USDW, the operator must shut-in the well immediately and a. The operator is ordered to repair the well within 60 days. b. If the operator fails to repair the well within 60 days, the District Deputy may rescind the permit by issuing a letter rescinding the individual injection-well permit and ordering the operator to disconnect the injection line at the wellhead within 10 days and notify the appropriate district office when the injection line has been disconnected. c. An MIT is required following repair if the well is returned to injection. d. The District Deputy must rescind the permit if the operator fails to repair the well within 120 days. e. An investigation must be conducted to determine if a USDW has been degraded. A finding that degradation has occurred as a result of injection operations must be supported with technical evidence and reported to the UIC Project Manager. C.Casing Failure Located Above The Packer Without Existing Fluid 1. If a casing hole located above the packer is in the permitted interval: a. The packer may be raised above the hole, making the hole the top perforation, or b. Without raising the packer, the operator must demonstrate mechanical integrity (MI) or develop a monitoring program. 2. If a casing hole is located above the packer and is above the permitted interval, the operator must demonstrate MI or develop a monitoring program. NOTE: A monitoring program should be designed as an early warning system to prevent USDW contamination. Periodic fluid level testing behind casing is one method of preventing USDW	Specify next steps.

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		contamination. 3. If a casing hole is located above the packer and in a USDW: a. The operator is ordered to repair the well within 60 days. b. If the operator fails to repair the well within 60 days, the District Deputy may rescind the permit c. An MIT is required following any repair if the well is returned to injection. If the operator fails to run the MIT d. The District Deputy must rescind the permit if the operator fails to repair the well within 120 days. External Mechanical Integrity Failure A. Migration Outside Casing Confined To Perimeter Zone If fluid exiting the approved perforations is not confined to the perforated interval, but is confined to the permitted zone, no action may be required other than monitoring as needed. An explanation and justification of the approved condition should be included in the well file, even if no action is required of the operator. B.Migration Outside Casing Not Threatening A USDW If fluid exiting the approved perforations is not confined to the permitted zone and does not pose a threat to a USDW: 1. The operator must repair the mechanical problem or amend the project to include the nonpermitted zone in the injection project by submitting the required project data within 60 days. No further injection is permitted until the project receives approval. 2. If the operator fails to repair the well or amend the project within 60 days, the District Deputy must rescind the permit. 3. An MIT is required following repair if the well is returned to injection. If the operator fails to run the MIT, ______ C. Migration Outside Casing Threatening A USDW 1.If fluid exiting the approved perforations is not confined to the permitted zone and is determined to pose a threat to a USDW, the operator is ordered to shut-in the well within 24 hours. 2.Operator is ordered to repair the well within 60 days.	

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		3. If the operator fails to repair the well within 60 days, the District Deputy rescinds the permit by issuing a letter rescinding the individual well permit and ordering the operator to: (1) shut-in the well within 24 hours (if the well is still active); (2) disconnect the in the wellhead within 10 days; and (3) notify the appropriate district office when the injection line has been disconnected. 4. An MIT is required following repair if the well is returned to injection. If the operator fails to run the MIT ________ D Migration Outside Casing Invading A USDW Or Flowing To Surface. 1. The operator should be ordered to shut-in the well immediately. 2. The operator is ordered to repair the well within 60 days. 3. If the operator fails to repair the well within 60 days, the District Deputy rescinds the permit by issuing a letter rescinding the individual well permit and ordering the operator to: (1) shut-in the well immediately (if the well is still active); (2) disconnect the injection line at the wellhead within 10 days; and (3) notify the appropriate district office when the injection line has been disconnected 4. An MIT is required following repair if the well is returned to injection. 5. An investigation must be conducted to determine if a USDW has been degraded. A finding that degradation has occurred as a result of injection operations must be supported with strong technical evidence and reported to the UIC Project Manager.	
		QUALITY ASSURANCE AND FLUID SAMPLING PROCEDURES Sampling Procedure The main objectives of the Division's sampling program are to control data accuracy and verify compliance with Division regulations by determining if there is the presence of a pollutant in surface or ground waters associated with a lack of confinement of the injection fluid to the approved zone. The accuracy of the chemical analysis is dependent on the sampling and sample-preservation method used. A. Coordination with Laboratories Communicating with laboratory personnel prior to sample collection is extremely important. Laboratories are to be contacted prior to any sample collection to schedule subsequent analysis. B. Sample Bottles	Fluid Sampling Process – separate section. Discussion on what tio include in the language and level of detail. Perhaps, these can be referenced in the regs. Research new technologies and consider in the language.

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Sample containers are either polyethylene or glass. The type of container will depend upon the suspected constituents. The size of the bottle depends upon the analysis to be conducted and the analytical methods used, as the volume of needed samples varies according to the methods used in the analyses and the preservation method. For analyzing the TDS of produced or injected waters, the amount of fluid collected should be about one quart or two 500 ml bottles. Sufficient samples shall be collected in case duplicate analysis should be required.

C.Sample Labels

Each sample bottle is labeled and identified with the following information:

- Date and time of sample collection.
- Operator, field, lease name, and well number.
- Section, Township and Range. B.& M.
- Name of individual(s) who performed the sampling.
- A description of where the sample was taken (e.g., wellhead, valve, tank number, etc.).
- Type of analysis desired.
- Any preservative used in the bottle.

The labels are to be fastened securely to the container. Labels should not be tied around the throat of the bottle or attached to the lid.

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D. Sample Forms

A sampling form should be completed for every sample that is collected. The form contains the same information that is found on the sample label, in addition to the following: (1) sample location; (2) sample procedure; (3) amount of fluid evacuated from a well or flushed through the system; (4) sample preservation used; (5) physical parameters measured in the field; and (6) detailed chain-of-custody record.

Once completed, the form is filed in the Injection Project file with a copy of the final fluid analysis.

E.Sampling Procedure

Division engineers, or its contractor/designee, must be assisted by a company representative before handling any oilfield equipment and collecting samples.

The sampling program is to collect a sample that is as representative of the injection or formation fluid as possible. For injection fluid samples, the injection fluid is collected from the injection line as close to the well head as possible. Also, samples are taken from the system when it is operating normally.

If collecting a sample from a flowline or wellhead valve after the system has been shut down for some time, or injection has not been constant, it may be necessary to let the fluid run out for a few minutes to flush the system. In cases where this is not possible, samples should be collected over time, such as every 5 or 10 minutes. These samples should be either combined into one large sample (a composite sample) or analyzed as individual samples.

Before filling, sample bottles shall be rinsed out two or three times, unless a preservative has been added to the bottle. If a sampling valve is available, a sampling tube shall be used to prevent aeration of the fluid sample when filling the sampling bottle. When sampling with a sampling tube, the end of the tube shall be placed in the bottom of the bottle until the bottle overflows for an estimated 10 volumes. The tube shall be pulled slowly from the bottle. To ensure a vacuum seal, the sides of the plastic bottle shall be squeezed as the cap is secured.

If a sampling valve is not available, then care should be taken to prevent turbulence in the fluid stream as it comes from the flowline or wellhead valve. A label shall be prepared immediately and affixed to the sample bottle.

When sampling a storage tank, care shall be taken to ensure that a representative sample is taken. Considerable stratification of fluids can occur in a tank if injection is intermittent. Therefore, samples shall be taken at different depths, from the liquid surface to the bottom. If the design of a tank permits, samples shall be collected from different areas and depths. These samples shall be mixed into one composite sample for analysis.

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If it is not possible to collect a storage-tank sample from the top of a tank because there is no available sampling hatch, then the sampling valve on the tank or flowline leading from the tank shall be used.

F. Formation Fluid Samples

The drill-stem test may be used to collect a formation water sample. Samples of the fluid may becollected as each stand of pipe is removed. A measurement of the resistivity (Rw) shall be taken for each sample and a total dissolved solids (TDS) value calculated. The most representative sample should be collected where the TDS becomes relatively constant.

Bailing may be used to collect a formation water sample. A bailer is raised and lowered in a well to collect small individual volumes of fluid. The use of a bailer as a sampling tool must be evaluated on a case-by-case basis.

Swabbing may be used to collect a formation water sample. Swabbing is preferable to drill-stem testing where unconsolidated formations cause testing difficulties. Swabbing may also be used in conjunction with drill-stem testing to increase the volume of fluid obtained.

A sample of formation water may be collected from a valve at the wellhead. A plastic tube may be used to transfer the fluid from the wellhead into a container. A large container or an oil-water separator with a valve at the bottom may be required due to mixing. The sample can then be collected from the bottom of the separator. To prevent mixing of oil and water, care should be taken to prevent turbulent flow from the wellhead valve into the oil-water separator. In some instances, it is necessary to discontinue the flow from the well and let the oil and water separate in the separator before collecting the sample.

As previously mentioned, it is important to remove several well volumes of water from a well prior to collecting a sample. The amount of water that should be removed from the well is dependent on the diameter of the well bore and the depth to the formation being sampled. A general rule is to evacuate free to five times the volume of water from the surface to the zone. For samples collected directly from a producing well, it is not necessary to evacuate a volume of the well; however, the well should be allowed to run just enough to flush out any contaminants in the valve.

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G. Sample Preservation

The importance of sample preservation. especially for formation fluid samples, cannot be over-emphasized. The quality of the sample analysis can only be assured through the maintenance of good procedures, from the time the sample is collected until it is delivered to the lab. Sample preservation should be performed in the field immediately after sample collection.

The object of preservation techniques is to preserve the stability of the constituents in the fluid. At best, the preservation technique can only retard the chemical and biological change that takes place in a fluid sample after it is removed from its source. Small changes in pressure and/or temperature, or exposure to the atmosphere, can result in significant changes to the concentration of the chemical components in the sample. For example, a change in fluid pressure would have the effect of releasing dissolved carbon dioxide to the atmosphere that, in turn, would cause a change of the Ph resulting in the precipitation of calcium carbonate. The analysis would then show a low reading of both carbon dioxide and calcium.

Methods of preservation are relatively limited and are intended to retard biological action and hydrolysis of chemical compounds, while reducing the volatility of constituents. Preservation methods are limited to Ph control, chemical addition, refrigeration, and freezing. The laboratory doing the analysis should be consulted for information on the proper preservation technique for the parameter being sampled. For example, the preservation technique for TDS determination is limited to refrigerating the sample to 40 C, with a maximum holding time of seven days .

Field measurements can provide laboratories with important information on the physical state of the fluid at the time it was collected. Also, these measurements can be used by the engineer to evaluate the results of the chemical analysis. Armed with basic knowledge of how certain physical changes affect chemical composition, an engineer can better evaluate the sample analysis, communicate with laboratories, and make compliance decisions based on sound evidence.

Division engineers collecting fluid samples witness the field measurements taken by company personnel or take the measurements themselves.

The most common and easiest field measurements to make are for temperature, Ph and electrical conductivity, and these parameters begin to change rapidly as soon as a sample is removed from a well; therefore, the fluid should be tested immediately.

NOTE: To ensure that thermometers, Ph meters, and conductivity meters are calibrated correctly, all physical measurements, as well as procedures used to take the measurements, should be described on the sample label and sample form.

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H. Chain of Custody Procedures

Any sample analysis used as evidence to support litigation must provide a chain-of-custody of the sample.

The objective of the chain-of-custody procedure is to create an accurate written record that can be used to trace the possession of the sample from the moment of its collection, through analysis, and until it is introduced as evidence. A sample is defined by EPA as being in someone's custody if:

- It is in one's actual possession; or
- It is in one's view, after being in one's physical possession; or
- It is in one's physical possession and then locked in a secure place; or
- It is kept in a secured area, restricted to authorized personnel.

The number of persons handling the sample must be kept to a minimum. The sampling form is filled out completely, signed, and dated by the person responsible for collecting or overseeing the collection of the sample. The sample bottle is sealed with tape, or a comparable seal around the cap, in a way that tampering would be easy to detect.

When transferring the sample, the transferee must sign and record the date, time, and to whom the

		sample was transferred. Every person who takes custody must fill in the appropriate section of the chain-of-custody record. To minimize custody records, the Division engineer must take the sample directly to the laboratory doing the analysis. This will not only ensure custody, but also will minimize the length of time from collection to analysis. If the sample analysis is to be used in litigation, the laboratory must be instructed to handle the sample as a custody sample and keep it locked up, except during the analysis. The sampling form containing the chain-of-custody record must be filed in the project file. At the time the analysis is returned, a note is made on the sampling form. Lab and Field Equipment Calibration Division field equipment is limited to a conductivity meter, Ph meter and a thermometer. The conductivity meter is calibrated against a standard KC1 solution and stored according to the manufacturer's specifications. Before sampling, checks must be made for measurement reliability. Also, the fluid vessel in the meter must be cleaned with distilled water after every use. Thermometers are calibrated against a National Bureau of Standards certified thermometer, and may be done by the lab at the time the sample bottles are picked up prior to sampling. Also if a Ph meter is used, the meter is calibrated using two buffers which bracket the Ph of the sample. For example, if the sample Ph is around 5, then Ph 4 and Ph 7 buffers would be used. It is important to note that a thermometer is mainly used when sampling formation fluids, since they are very susceptible to temperature and pressure changes during sampling. The calibration of laboratory equipment is not applicable to the Division's QA program because the Division does not exercise authority over labs. Analytical Procedures Laboratories performing fluid analyses on samples collected for the UIC Program are sent a copy of the Federal Register containing EPA accepted methodologies, with instructions that these procedures be followed. Internal Quality Control Checks The Division uses only those labs certified by the State or labs proven to be reliable in the analysis of waste-water samples. All quality control checks are in conformance with State lab-certification requirements. However, a list of Quality Control (QC) Procedures is submitted to the lab performing the analysis with instructions that these procedures be followed. This list pertains to standard curve data, standardization of titrants, electrochemical methods, analytical balances, duplicate analysis, and spiked sample analysis.	

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		Performance and Systems Audits Performance and system audits performed by the Division are limited to the use of QC samples. The Division provides the laboratories with "QC samples" for analysis. A comparison of the results with the known values indicates the quality of the analysis done by the lab. Samples used for QC may be provided by the EPA, or the Division may split samples between two labs. These QC checks should be performed periodically, and mainly with labs used regularly by the Division, unless the labs are State-certified.	
New section Commencement, discontinuance, abandonment of injection	XXX	Commencement, Discontinuance and Abandonment of Injection Operations A. The following provisions apply to all injection projects, storage projects, salt water disposal wells and special purpose injection wells: B. Notice of Commencement and Discontinuance (1) Immediately upon the commencement of injection operations in any well, the operator shall notify the Division of the date such operations began. (2) Within 30 days after permanent cessation of gas or liquefied petroleum gas storage operations or within 30 days after discontinuance of injection operations into any other well, the operator shall notify the Division of the date of such discontinuance and the reasons therefore. (3) Before any injection well is temporarily abandoned or plugged, the operator shall obtain approval from the appropriate district office of the Division in the same manner as when temporarily abandoning or plugging oil and gas wells or dry holes. C. Abandonment of Injection Operations (1) Whenever there is a continuous two year period of non-injection into any injection project, storage project, salt water disposal well, or special purpose injection well, such project or well shall be considered abandoned, and the authority for injection shall automatically terminate ipso facto.	
	XXXX	Records and Reports: A. The operator of an injection well or project for secondary or other enhanced recovery, pressure maintenance, natural gas storage, salt water disposal, or injection of any other fluids shall keep accurate records and shall report monthly to the Division gas or fluid volumes injected, stored, and/or produced as required on the 110B form.	
	XXXX	Transfer of Authority to Inject	Create a form

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		A. Authority to inject granted under any approval from the Division is not transferable except upon approval of the Division. Approval of transfer of authority to inject may be obtained by filing Form ____. B. The Division may require a demonstration of mechanical integrity prior to approving transfer of authority to inject.	
	XXXX	Disposition of Transported Produced Water A. No person, including any transporter, may dispose of produced water on the surface of the ground, or in any pit, pond, lake, depression, draw, streambed, or arroyo, or in any watercourse, or in any other place or in any manner which will constitute a hazard to any fresh water supplies, unless approval is granted by the Regional Water Quality Control Board. B. Delivery of produced water to approved salt water disposal facilities, secondary recovery or pressure maintenance injection facilities, or to a drill site for use in drilling fluid will not be construed as constituting a hazard to fresh water supplies provided the produced waters are placed in tanks or other impermeable storage at such facilities. C. The district deputy of the appropriate district office of the Division may grant temporary exceptions to Paragraph A. above for emergency situations, for use of produced water in road construction or maintenance, or for use of produced waters for other construction purposes upon request and a proper showing by a holder of an approval by the Regional Water Quality Control Board	
Clarification re Division's role in surface waste management facilities	XXXX	Surface Waste Management Facilities A surface waste management facility is defined as any facility that receives for collection, disposal, evaporation, remediation, reclamation, treatment or storage any produced water, drilling fluids, drill cuttings, completion fluids, contaminated soils, bottom sediment and water (BS&W), tank bottoms, waste oil or other oilfield related waste. These facilities are not permitted by the Division, but by other federal, state, and/or local jurisdictions.	Specific to surface waste management facilities only

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Monitoring Programs	1724.11	Monitoring Well Programs for Underground Injection Projects. (a) If one or more wells within the area affected by underground injection project have the potential to act as a conduit for injection fluid, and the supervisor determines that it is not feasible to remediate the potential conduit wells, then the supervisor may approve a project that relies upon a monitoring well program, as described in subdivision (b), to ensure that injection operations will not cause damage to life, health, property, or natural resources. (b) A monitoring well program shall be designed to ensure that wells that are potential conduits for injection fluid are not affected by injection operations. An operator proposing to employ a monitoring well program must demonstrate to the supervisor's satisfaction that all of the following requirements will be met: (1) Monitoring wells shall be sufficient in number and location for determining all of the following: (A) The direction and rate of regional groundwater movement. (B) Any upward migration of injection fluid and changes in water quality in the water bearing formation immediately above the injection zone. (C) The direction, rate, hydraulic effects, alteration, and characteristics of fluids injected into the injection zone, and any changes of pressure within or above the injection zone. (2) Continuous recording devices shall be installed and maintained in proper operating condition at all times to record injection pressures, injection flow rates, injection volumes, and annulus pressure. (3) Monitoring wells shall not be located within the influence of any adjacent pumping wells that might impair their effectiveness. (4) Monitoring wells shall only be screened in the strata to be monitored. (5) Monitoring wells shall be monitored for pressure in all monitored strata and for water quality in the water-bearing strata. (6) The casing diameter of the monitoring wells shall allow an adequate amount of water to be removed during sampling and shall allow full development of the monitoring well.	

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		(7) Monitoring wells shall be constructed so as not to provide potential conduits for migration of injection fluids. (8) Water samples shall be collected, handled, and transported in accordance with the United States Geological Survey's "National Handbook of Recommended Methods for Water-Data Acquisition." For all monitoring wells, except those extending into the injection zone, the sample shall be collected after at least five well volumes have been removed from the well. (9) The frequency of monitoring shall be sufficient to give timely warning of migration of injection fluids so that remedial action can be taken prior to any damage occurring. The supervisor may increase or decrease the frequency of monitoring for an approved monitoring well program based upon the available data. (10) If there is indication that injection fluid has or is likely to migrate to any strata outside the in intended zone of injection, the operator shall immediately suspend injection operations until a remedial plan is approved by the supervisor.	

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